Hawaiian Electric Company, Inc. • PO Box 2750 • Honolulu, HI 96840-0001

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March 30, 2009

FILED

2009 MAR 30 P 4:15

PUBLIC UTILITIES COMMISSION

The Honorable Chairman and Members of
the Hawaii Public Utilities Commission
Kekuanaoa Building, 1st Floor
465 South King Street
Honolulu, Hawaii 96813

Dear Commissioners:

Subject: Docket No. 2008-0274 – Decoupling Proceeding
<u>HECO Companies' Responses to Information Requests</u>

Enclosed for filing are the HECO Companies' responses to the information requests ("IRs") prepared by the Commission's consultant, the National Regulatory Research Institute, and submitted to the parties in this proceeding on March 5, 2009.[1] As the Commission requested the parties to respond to the IRs within 21 days and served the parties by mail, these responses are timely filed.

Sincerely,

Enclosures

cc: Division of Consumer Advocacy
Hawaii Renewable Energy Alliance
Haiku Design and Analysis
Hawaii Holdings, LLC, dba First Wind Hawaii
Department of Business, Economic Development, and Tourism
Hawaii Solar Energy Association
Blue Planet Foundation

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[1] The "HECO Companies" are Hawaiian Electric Company, Inc., Hawaii Electric Light Company, Inc. and Maui Electric Company, Ltd.

PUC-IR-1

At the technical workshop, the difference between marginal cost included in a provided table and that should be recovered through the volumetric charges in a SFV rate was discussed. Please provide the two marginal costs for each rate class and describe the difference.

<u>HECO Response:</u>

For the purpose of this response, the Company understands the marginal cost is referring to the marginal cost referenced by Haiku Design and Analysis ("HDA") in Attachment 1 of its response to the National Regulatory Research Institute scoping paper, Appendix 2: Questions to the Parties ("NRRI Scoping Paper Questions"). This marginal cost is a marginal energy cost comprised of fuel, variable cost, and other adjustments which is presented in HECO's 2005 test year rate case testimony. See Attachment 1 to this response, which is HECO workpaper HECO-RWP-2214, p. 2, from HECO's 2005 rate case. The Company understands the other reference to be to the revenue that is recovered through volumetric charges, as in a SFV rate design.

The customer charge in the Company's rates is the fixed component of rates. The Company recovers most of its revenue through volumetric charges for energy and demand as shown in the 2005 test year rate case rebuttal testimony workpapers that are attached. The Company's marginal energy cost is used as a guide to rate design but is not an element of the Company's test year costs nor is it part of the rate design in and of itself.

HDA uses Attachment 1 of its response to the NRRI Appendix 2 questions as the basis for its contention that Schedules PT, PP, and PS are already essentially decoupled because their marginal revenues by rate schedule are almost equal to marginal energy delivery costs by rate schedule. (See HDA's responses to the NRRI Scoping Paper Question #2, page 5.) However, HECO maintains that the information which HDA reasonably relied upon to build Attachment 1 to its response to the NRRI Appendix 2 questions is not appropriate for the purpose used.

For HECO Schedules PT, PP, and PS, the HDA analysis uses the lowest tier of the energy rate pricing as the assumed marginal revenue per kWh. HECO's marginal revenue from Schedules PT, PP, and PS is dependent on the customer or customers that generate the marginal revenue, and in fact, it is difficult to generalize what the marginal revenue or the marginal revenue rate might be for those rate schedules. However, it would be reasonable to say that the marginal revenues are likely higher than what is represented by the lowest tier of energy rate pricing.

Furthermore, the marginal energy unit costs in HECO-RWP-2214, p. 2, may not accurately represent marginal unit costs. First, the marginal costs in HECO-RWP-2214 were developed using fuel prices higher than the fuel prices used as the cost basis for base rates in the 2005 HECO test year rate case. Therefore, had marginal costs been calculated using the fuel prices used as the cost basis for base rates, they would likely have been lower than shown in HECO-RWP-2214, p. 2. Second, the marginal costs shown in HECO-RWP-2214, p. 2 were developed based on a 1 mWh change in sales, which may not accurately represent the marginal energy costs for a larger change in sales. As a result, the marginal energy costs cannot be compared against the test year rate design, which is the basis of HDA's Attachment 1 in its response to NRRI Appendix 2 questions.

The Company's volumetric charges recover test year costs that are fixed in nature such as generation, transmission, and distribution facility costs as well as test year costs that are variable in nature such as fuel costs and purchased energy costs.

PUC-IR-2

Please discuss the service quality standards, such as the one mentioned in RAP's Revenue Decoupling- Standards and Criteria for the Minnesota Public Utilities Commission, dated June 30, 2008, which are intended to overcome an indifference to lost services that sales decoupling may create.

HECO Response:

The HECO Companies' decoupling proposal is consistent with the HCEI agreement, and does not include service quality provisions. Quality provisions are not commonly found in revenue decoupling plans. To understand why, consider that a utility's service quality is most likely to be jeopardized when real profits are to be made by cutting line maintenance expenses and other costs of maintaining or improving quality. Experience has shown that these profit opportunities depend chiefly on the length of time between rate cases. The great majority of decoupling plans do not involve rate case moratoria lasting four years or longer. Many decoupling plans in fact involve no rate case moratorium. Four years is normally considered the threshold term that would qualify an alternative regulation plan to be classified as an example of performance-based regulation ("PBR"), with cost containment incentives sufficiently strong to warrant quality concerns. Where quality provisions are included in PBR plans, they oftentimes involve only the monitoring of quality and not a program of awards and/or penalties, especially in first generation plans.

Shirley, Lazar, and Weston implicitly acknowledge these realities in their recent white paper on decoupling for the Minnesota Public Utilities Commission.[1] They state on page 29 of their paper that:

[1] Wayne Shirley, Jim Lazar, and Frederick Weston, *Revenue Decoupling: Standards and Criteria*, Regulatory Assistance Project, June 30 2008.

> We doubt that decoupling, by itself, would lead to an erosion of customer service (and, indeed, we've seen no evidence of it in other jurisdictions). Public opinion, general regulatory oversight, and the utility's corporate culture are probably sufficient to prevent it. Even so, customer service standards make sense as a general matter, particularly in conjunction with a multi-year rate plan. Consideration of a decoupling proposal provides an opportunity to develop and implement such standards, if they are lacking.

Evidently, the authors believe in customer service standards "as a general matter", and see decoupling as an opportunity to introduce such standards even if there is no evidence that decoupling raises quality concerns.

The HECO Companies are proposing three-year plans, in conformance with the traditional California general rate case cycle. Three-year RAMs in California are not generally viewed as PBR plans and have usually not involved service quality provisions. Note also that in the Companies' January 30, 2009 proposal, it states:

> "The HECO Companies have not proposed an earning sharing mechanism, but would be willing to consider one if it operated symmetrically both above and below a baseline and was fair to both customers and shareholders of the Companies."

In the joint Statement of Position filed March 30, 2009 by the Consumer Advocate and the HECO Companies, the Consumer Advocate and HECO Companies have included an earnings sharing mechanism ("ESM") in their decoupling plans, in addition to the traditional approach to RAM design that the HECO Companies had originally proposed on January 30,2009, in order to assuage concerns that the RAM will create windfall gains through improvident design. An ESM would, by sharing any surplus earnings with customers, further weaken incentives to take extreme cost containment measures that could jeopardize quality.

In The Regulatory Assistance Project's ("RAP") April 22 to 23, 2008 presentation in Honolulu as part of the Hawaii Clean Energy Initiative workshop, Wayne Shirley also did not include service quality standards in his *Utility Incentives and Disincentives* decoupling presentation.

The introduction of service quality standards therefore appears to the HECO Companies to be an unnecessary complication. If standards are introduced, the HECO Companies recommend starting with a service quality monitoring program that does not involve awards or penalties.

PUC-IR-3

At the technical workshop, the participants discussed that the proposed decoupling adjustment would create a bias for the utility to overstate test year sales and for rate increase opponents to understate test year sales. Please discuss.

HECO Response:

Controversy over future sales volumes is a common feature of rate cases. Under traditional ratemaking, opponents of rate increases have some incentive to exaggerate future volumes inasmuch as higher volumes produce lower volumetric rates. Proponents of rate increases have some incentive to understate future volumes in order to forecast higher volumetric rates. Clearly these positions are opposite of the suggestion that utilities have a bias to overstate test year sales and rate increase opponents have a bias to understate test year sales for the decoupling adjustment (which suggests an effort to manage the size of the decoupling adjustment instead of the total rate case impact).

Under sales decoupling, the test year sales estimate is only of interest to the utility and to rate increase opponents to the extent it affects the estimate of O&M expenses, such as fuel and purchased energy expenses (which are recovered through the Energy Cost Adjustment Clause) and the number of new customer connections, for example. The authorized base revenue resulting from the rate case is otherwise not a function of the test year sales estimate. Both the utility and rate increase opponents are less concerned about base rates set in a rate proceeding since those rates are subject to the Revenue Balancing Account ("RBA") rate adjustments which adjust rates for actual annual sales and recorded revenues to provide for the recovery of the Commission-approved target revenue. This is accomplished through the Companies' proposed RBA and Revenue Adjustment Mechanism ("RAM") Provisions.

Forecasting controversy is exacerbated in times of uncertain economic activity such as utilities across the country currently face. A decoupling mechanism greatly reduces the importance of volume forecasts in ratemaking since rates are adjusted automatically to recover the revenue requirement when actual volumes differ from forecasts. For example, HECO has not revised its volume forecast in its current 2009 test year rate case despite a worsening local economy. Upon Commission approval of a decoupling mechanism, the difference between HECO's approved revenue requirement and billed revenue collected from actual sales, will be recovered through the proposed sales decoupling mechanism[1], the revenue balancing account, which neutralizes the impact of forecasting error on revenue.[2]

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[1] The HECO Companies' decoupling proposal includes two components, a sales decoupling component via the revenue balancing account ("RBA") and a revenue adjustment mechanism ("RAM") component to adjust the HECO Companies' annual revenue requirements for input price changes and the balance in the RBA.
[2] See HECO T-1 Rate Case Update, pages 10-11, filed December 23, 2008, in Docket No. 2008-0083.

PUC-IR-4

At the technical workshop, HECO or its consultants mentioned how sales decoupling does not shift risk between the utility and customers but rather lowers total risk. How is this risk reduction included in HECO's current rate case and its requested rate of return?

HECO Response:

The HECO Companies would like to clarify what was said at the technical workshop. An appropriate decoupling mechanism lowers the risk of the HECO Companies by ensuring that revenue equals the revenue requirement; but it also stabilizes consumer expenditures and ensures that consumer expenditures equals the revenue requirement. So, in a year with a booming tourist economy and/or unusually hot weather, customers do not pay any more for base rate services; nor do the Companies collect any more revenue for the increased usage. Similarly, in a year with a depressed economy and/or unusually cool weather, customers do not pay any less for base rate services; nor do the Companies collect any less revenue for the lower usage.

Please see response to Appendix 2 – Question 7 filed on February 20, 2009 which addresses changes in risk resulting from decoupling, risks associated with the numerous massive and substantive projects which the HECO Companies have committed to undertake in the HCEI Agreement, and impacts on the utility's requested rate of return.

PUC-IR-5

Dr. Lowry stated at the technical workshop that a RAM would not be needed with a straight fixed variable rate design.

a. Why would a RAM be needed with a revenue per customer decoupling mechanism that works arithmetically the same as SFV rate design according to NRRI's scoping paper?
b. Please discuss if the Commission should consider a SFV decoupling approach and avoid the need for a RAM?
c. If the Commission were to adopt a SFV rate design, please suggest a potential for a revenue neutral energy efficiency rebate as discussed in the scoping paper.

<u>HECO Response:</u>

a. A revenue per customer decoupling mechanism such as that described in the NRRI Scoping Paper is classified as a revenue per customer freeze ("RPC freeze") in PEG's white paper, *Revenue Decoupling for Hawaiian Electric Companies,* which was filed on January 30, 2009 with the HECO Companies' proposal as Attachment 1, pages 10 to 15 (Section 2.2.2). PEG explains in Section 2.2.2 of the paper that a RAM of this kind does not escalate a utility's revenue requirement for input price and productivity growth. As such, it provides inadequate attrition relief because input price inflation is usually well in excess of productivity growth. Shirley, Lazar, and Weston, in their recent paper on decoupling for the Minnesota Public Utilities Commission, describe a "well designed decoupling program" as "one that possibly allows for adjustments according to changes in short-run drivers such as numbers of customers, inflation, and productivity."[1]

To avoid financial attrition, utilities operating under RPC freezes file rate cases more frequently. This raises regulatory cost and can compromise utility cost performance. A RAM that provides relief for inflation as well as customer and activity growth makes it

[1] Wayne Shirley, Jim Lazar, and Frederick Weston, *Revenue Decoupling: Standards and Criteria*, Regulatory Assistance Project, 30 June 2008, p. 9.

possible to simultaneously reduce regulatory cost and improve utility performance. That is why most RAMs that have been implemented in the U.S. and other countries over the years have not employed a RPC freeze.

b. A lively debate has developed in some jurisdictions over the relative merits of SFV pricing and the true up approach to decoupling. We present here a distillation of some of the central arguments over conventional SFV pricing.

1. Pricing Issues

Impact on Conservation

The hallmark of conventional SFV pricing is low volumetric charges that afford customers unlimited system use for a fixed monthly fee. This is akin to an all-you-can-eat buffet or a car rental contract with no mileage charge. Greater purchases of energy are encouraged and customers cannot individually reduce their bill for distribution services by purchasing less energy. SFV pricing thus reduces the net impact of decoupling on volume growth. The Arizona Corporation Commission, in rejecting a proposal by Southwest Gas for aggressive movement towards SFV pricing, stated in this regard that:

> The Southwest Gas rate design would have the effect of encouraging greater use of natural gas at a time when, by all accounts, an increase in demand for gas is coupled with shortages in supply. We do not believe that it is appropriate to send a signal to customers of 'the more you use the more you save'.[2]

[2] Opinion and Order, Docket No. G-01551A-04-0876 [In the Matter of the Application of Southwest Gas Corporation for Establishment of Just and Reasonable Rates and Charges Designed to Realize a Reasonable Rate of Return on the Fair Value of the Properties of Southwest Gas Corporation Devoted to its Operations Throughout the State of Arizona], Feb. 23 2006, p. 37.

The erosion of conservation is apt to be greater for a vertically integrated electric utility than for a power transmission and distribution ("T&D") utility because SFV pricing would remove the fixed costs of power generation from volumetric charges as well as the fixed costs of T&D.

The true-up approach to decoupling, in contrast, permits utilities to maintain current volumetric charges or even increase them as a tool to promote DSM and customer-sited DG. Experience has shown that high volumetric charges are an especially effective tool since they involve low administrative costs and can substantially reduce the payback period for conservation and DG. This attribute of the true-up approach is more advantageous to the extent that greater conservation and customer-sited DG are important decoupling goals.

Proponents of SFV pricing often say that a large part of a customer's bill still consists of volumetric charges that are designed to recover the cost of energy that the utility purchases. These charges loom especially large when energy prices are high. This argument has less force for vertically integrated electric utilities than it does for T&D utilities since, for the former group, commodity costs are a smaller part of the cost of service. For energy utilities of all kinds, it should be noted that energy prices are volatile, and prolonged periods of low prices can follow price spikes. Moreover, a 20-50% reduction in the total volumetric charge such as may be expected under SFV pricing can have a real impact on volumes in the longer run. Interstate natural gas shippers have faced SFV pricing for transportation services and volumetric pricing for the gas commodity since 1993. From 1993 to 2007, U.S. natural gas consumption increased 11% despite a threefold increase in the wellhead price of gas. This was due, chiefly, to rising use of gas in power generation that was encouraged by low volumetric charges. Shirley, Lazar, and Weston calculate that, in the case of a gas distributor, "a shift from pure volumetric pricing to pure SFV pricing could result in an 18% increase in the quantity of natural gas required to meet customer needs, even with continued volumetric pricing of gas commodity."[3]

Efficiency of Low Customer Charges

Proponents of SFV pricing also maintain that it is important to send customers the right price signals even if greater conservation is desirable. They argue that the cost of base rate inputs is for the most part fixed in the short run. Volumetric charges that exceed the short run marginal cost of system use discourage socially beneficial uses of power and encourage inefficient DG.

SFV pricing may be more efficient than the current pricing schemes of utilities under some circumstances but the argument that it is fully efficient under all circumstances can be challenged. The volume of energy that a utility supplies and/or delivers may have a material impact on the cost of its base rate inputs in the longer run. The long run marginal cost can thus be appreciably higher than the short run marginal cost. This reality is particularly easy to grasp in the case of vertically integrated electric utilities because they typically own and operate extensive generation capacity that is designed to serve base load. The volumetric charges for the use of base rate inputs should equal the long run marginal cost of service in the long run but, under conventional SFV pricing, would chronically be set at the lower short run marginal cost.

[3] Shirley, Lazar, and Weston *op cit* p. 22.

High Customer Charges

Conventional SFV pricing typically involves a substantial increase in residential customer charges to a level that is the same for all customers. These can lower bills for large-volume customers but can raise bills substantially for small-volume buyers. Low volume customers include some who are trying especially hard to conserve energy and/or to rely on customer-sited renewable energy. Moreover, many small-volume customers have low incomes, although the correspondence here is not perfect. Many small volume customers live in multiple occupant dwellings such as apartment buildings. Small volume customers are often subject to special protections in utility regulation. An abrupt move to SFV pricing may violate the principle of rate gradualism.

Critics of SFV pricing also argue that cost depends, in the long run, on delivery volumes and peak system use. The importance of these variables as cost drivers is well-recognized inasmuch as they are frequently used in traditional cost of service studies as criteria for allocating the revenue requirement. Large volume residential customers have larger delivery volumes than small volume customers by definition and also typically make greater use of the system on peak demand days. The uniformly high residential customer charges that result from conventional SFV pricing are therefore inconsistent with traditional principles of cost causation. However, this problem can be ameliorated by a "sliding scale" system whereby customer charges vary in some rough fashion with historical consumption.

2. Simplicity

Conventional SFV pricing has appreciable advantages over the true up approach to decoupling in the area of simplicity. There is, most obviously, no need for periodic true ups and revenue grows automatically with customer and activity growth, much as it would under a decoupling true up plan with a RPC freeze. This simplicity advantage is offset to the extent that the true up approach involves a RAM that adjusts automatically for input price inflation as well as customer and activity growth and thereby permits a material reduction in the frequency of rate cases.

3. Precedents

The precedents for each approach to decoupling are also relevant to the discussion. Greater use of one approach over another may indicate underlying advantages, and established approaches provide opportunities for regulators to "work the bugs out." We have seen that the true up approach to decoupling has been much more popular to date in the regulation of U.S. energy utilities. There has to our knowledge been no use of SFV pricing in the electric power industry.

As for other industries, flat fee pricing is encountered in a number of consumer services, including internet and basic telephone and cable TV services. These are industries in which the number of customers served has an especially large impact on the cost of service. However, companies in most businesses recover most or all of their fixed costs through usage charges Airports, tunnels, hotels, and major bridge projects are examples of comparatively capital intensive businesses that draw most of their revenue from usage fees.

4. Commentary

This analysis suggests that the true up approach to decoupling is apt to be especially advantageous relative to conventional SFV pricing to the extent that the following conditions hold:

- The decoupling mechanism is part of a package of measures that is intended to promote slower growth in sales per customer in addition to compensating the utility for a decline that is already underway.
- The long run marginal cost of the base rate inputs used to procure and deliver a unit of energy is well above its short run marginal cost. This is more likely to be true for a vertically integrated electric utility than it is for an energy T&D utility.
- The supplemental charge for the purchase of energy commodities is low. This is more likely to be true for a vertically integrated electric utility than it is for an energy T&D utility since it is engaged in power production.

The conditions favoring the true up approach seem to be especially likely to hold for vertically integrated U.S. electric utilities such as the HECO companies. SFV pricing may have more appeal in applications to gas utilities. Our analysis may help to explain why the use of SFV pricing has been confined to gas utilities.

c. A feebate system can rectify some of the problems with conventional SFV pricing that were just discussed in our response to subpart 5b above. The feebate rate can be designed so that customers face the long run marginal cost to society of purchasing a unit of energy. Large volume customers will then make transfers to low volume customers and bills will vary more sensibly with different usage levels.

However, feebate systems are complicated and would be difficult to explain to customers. This would greatly erode the central advantage of conventional SFV pricing – its simplicity. Moreover, there is little or no experience with feebates and many bugs will doubtless need to be worked out before it is ever ready for widespread use in regulation. Conventional SFV pricing caused many problems when it was first implemented for a retail gas utility (Atlanta Gas Light).[4] HECO is, in contrast, proposing an approach to decoupling that has been used for more than twenty five years.

[4] See Georgia Docket No. 8390-U. According to the October 6 2000 issue of the *Gas Utility Report*, "following deregulation, the utility implemented a fixed rate design recovering the same amount each month, but it has been a source of annoyance for customers because of the resulting increase in summer rates when gas use is low."

PUC-IR-6

At Attachment 5A page 1 of 11 and Attachment 15A.2 page 1 of 11 of the PEG report, the RAM for HECO for 2010 and 2011 is $ 6.1 million and $5.4 million for O&M and $10 million and $2.4 million for growth in the rate base.

a. Is the total RAM for 2010 and 2011 estimated to be $16.1 million and $7.8 million?
b. What is the estimated increase for the 2012 rate case?
c. Is this RAM in addition to revenues associated with the REIS?

HECO Response:

a. No. The $10 million and $2.4 million of estimated RAM revenues associated with HECO's 2010 and 2011 rate bases in Attachment 15A.2 of the Companies' January 30, 2009 proposal were estimated to reflect the full year impact of the significant project, East Oahu Transmission Project ("EOTP"), for illustrative purposes only. When implementing the RAM, the Companies' proposal is that the RAM associated with the rate base without the significant project(s) should be effective, until the significant project(s) are placed into service. At the time during the post test year that the significant project(s) is(are) actually placed into service, the rate base RAM will be revised to reflect the full cost of the significant project(s), limited to its authorized amount and an additional 10%, with the revenue balancing account to be adjusted a month later.[1] Using the Companies' most current estimated in service date of June 2010 for EOTP (currently the only significant project anticipated to be placed into service in 2010), the RAM for the first six months of 2010 will be based on an average rate base of $1,427,900 and the remaining six months will be based on an average rate base of $1,444,698. This is analogous of having a weighted rate base in effect for the post test year, resulting in estimated RAMs of $8.3 million and $4.1 million for years 2010 and 2011, respectively (see Attachment 1 to this response for

[1] HECO Companies' decoupling proposal, filed January 30, 2009, at 31.

the calculation of the rate bases using the June 2010 service date for EOTP and the associated RAMs). Adding in the estimated O&M RAMs, the total RAMs for 2010 and 2011 are estimated at $14.4 million and $9.5 million.[2]

However, as noted on page 21 of the Companies' January 30, 2009 decoupling proposal, for each of the post test years, the actual O&M RAM to be implemented will be based on the expenses and taxes that are approved by the Commission in the Companies' 2009 rate cases (interim and final orders) and the latest available Global Insight forecast of the expense inflators prior to the post test year. The actual rate base RAM to be implemented will be based on the expenses (e.g., uncollectibles) and taxes that are approved by the Commission in the Companies' 2009 rate cases (interim and final orders) and the significant projects (capital improvement projects and software development projects) that are approved by the Commission actually placed into service.

b. Hawaiian Electric Company, Inc. ("HECO") does not currently plan to file a 2012 rate case. On page 11 of the Companies' proposal, depending on the outcome of the 2009 rate case and the instant proceeding, the next HECO rate case is anticipated to be filed in 2010 for a 2011 test year.

c. Yes. Per the Section 28 of the October 2008 HCEI Agreement (the relevant portion of which was re-stated on page 4 of the HECO Companies' Revenue Decoupling Proposal (corrected 2/3/09)) the capital investments to be included in the rate base RAM exclude those projects which are recovered via the Clean Energy Infrastructure Surcharge (originally the Renewable Energy Infrastructure Surcharge, or REIS). Please see also the

[2] 2010 RAM = $6.1M (O&M) + $8.3M (RB) = $14.4M. 2011 RAM = $5.4M (O&M) + $4.1M (RB) = $9.5M.

HECO Companies' response to the NRRI Scoping Paper, Appendix 2, question #12, filed February 20, 2009, which states:

> The HCEI Agreement proposes a Clean Energy Initiative ("CEI") surcharge to recover the return on and return of investments in renewable energy infrastructure and a purchased power adjustment to recover non-energy purchased power costs not already covered by the Energy Cost Adjustment Clause. Since these fixed costs and non-energy purchased power expenses are proposed to be recovered outside of base rates, they are not covered by the sales decoupling mechanism, nor should they be...

"Significant Projects at Full Cost at Time of Inservice" Methodology

(In $000s)

HECO Average Rate Base with no significant projects		2009	2010	2011
Average Rate Base - Base - 2009	N.1	$ 1,334,931	$ 1,334,931	NA
Rate Base Growth ($15,177K per year)	N.2	$ -	$ 15,177	NA
		$ 1,334,931	$ 1,350,108	NA
Significant Project Impact (Average)	N.3			
1/2 of CIP CT-1			$ 77,792	NA
No Significant Projects			$ -	NA
Total Average Rate Base		$ 1,334,931	$ 1,427,900	$ -

HECO Average Rate Base (with EOTP at full cost)		2009	2010	2011
Average Rate Base - Base - 2009	N.1	$ 1,334,931	$ 1,334,931	$ 1,334,931
Rate Base Growth ($15,177K per year)	N.2	$ -	$ 15,177	$ 30,354
		$ 1,334,931	$ 1,350,108	$ 1,365,285
Significant Project Impact (Full Cost)	N.3			
1/2 of CIP CT-1			$ 77,792	$ 74,826
EOTP (in service date of June 2010)			$ 16,798	$ 16,016
Total Average Rate Base		$ 1,334,931	$ 1,444,698	$ 1,456,127

* EOTP is currently scheduled to be placed into service in June 2010

Weighted Average of Rate Base		
January through June 2010	$713,950	NA
July through December	$722,349	NA
Average Rate Base	**$1,436,299**	**$ 1,456,127**

Hawaiian Electric Company, Inc
Rate Base RAM (HECO Significant Project Methodology - EOTP In Service in June 2010)
Results of Operations
Based on 2009 Test Year
($ Thousands)

	Current Effective Rates	Additional Amount	Revenue Requirements to Produce 8.81% Return on Average Rate Base	2009 Nominal Amount (N 1)	2009 BAU Amount	2009 1 + Index	Notes	2010 BAU * Index Amount	2010 Nominal Amount (N 1)	**2010 TOTAL RAM Amount**	Notes	2010 Nominal Amount	2011 BAU Amount	2011 1 + Index	Notes	2011 BAU * Index Amount	2011 Nominal Amount	**2011 TOTAL RAM Amount**	Notes
Electric Sales Revenue	1,861,751	99,913	1,961,664					0		**1,969,975**	N 11							**1,974,106**	N 11
Other Operating Revenue	4,487	122	4,609	4,609	0			0	4,609	**4,609**		4,609					4,609	**4,609**	
Gain on Sale of Land	615		615	615	0	100.0%	N 2	0	615	**615**		615	0	100.0%	N 2	0	615	**615**	
TOTAL OPERATING REVENUES	1,866,853	100,035	1,966,888	5,224	0			0		**1,975,199**		5,224	0			0		**1,979,330**	
Fuel	816,654		816,654	816,654	0	100.0%	N 2	0	816,654	**816,654**		816,654	0	100.0%	N 2	0	816,654	**816,654**	
Purchased Power	477,055		477,055	477,055	0	100.0%	N 2	0	477,055	**477,055**		477,055	0	100.0%	N 2	0	477,055	**477,055**	
Production	82,423		82,423																
Production Labor *			33,819		33,819	100.0%	N 2	33,819		**33,819**		0	33,819	100.0%	N 2	33,819		**33,819**	
Production NonLabor *			48,604	0	48,604	100.0%	N 2	48,604	0	**48,604**		0	48,604	100.0%	N 2	48,604	0	**48,604**	
Transmission	13,930		13,930																
Transmission Labor *			4,951		4,951	100.0%	N 2	4,951		**4,951**		0	4,951	100.0%	N 2	4,951		**4,951**	
Transmission NonLabor *			8,979		8,979	100.0%	N 2	8,979		**8,979**		0	8,979	100.0%	N 2	8,979		**8,979**	
Distribution	30,515		30,515																
Distribution Labor *			12,474		12,474	100.0%	N 2	12,474		**12,474**		0	12,474	100.0%	N 2	12,474		**12,474**	
Distribution NonLabor *			18,041	0	18,041	100.0%	N 2	18,041	0	**18,041**		0	18,041	100.0%	N 2	18,041	0	**18,041**	
Customer Accounts	16,297		16,297																
Customer Accounts Labor *			7,729		7,729	100.0%	N 2	7,729		**7,729**		0	7,729	100.0%	N 2	7,729		**7,729**	
Customer Accounts NonLabor *			8,568	0	8,568	100.0%	N 2	8,568	0	**8,568**		0	8,568	100.0%	N 2	8,568	0	**8,568**	
Allowance for Uncoll Accounts	1,339	72	1,411		1,411	100.6%	N 13	1,420		**1,420**		0	1,420	100.5%	N 13	1,427		**1,427**	
Customer Service	6,997		6,997																
Customer Service Labor *			964		964	100.0%	N 2	964		**964**		0	964	100.0%	N 2	964		**964**	
Customer Service NonLabor *			6,033		6,033	100.0%	N 2	6,033		**6,033**		0	6,033	100.0%	N 2	6,033		**6,033**	
Administration & General	77,863		77,863							**0**		0						**0**	
Admin & Gen Labor *			21,199		21,199	100.0%	N 2	21,199		**21,199**		0	21,199	100.0%	N 2	21,199		**21,199**	
Admin & Gen NonLabor *			56,664	19,098	37,566	100.0%	N 2	37,566	19,098	**56,664**		19,098	37,566	100.0%	N 2	37,566	19,098	**56,664**	
Operation and Maintenance	1,523,073	72	1,523,145	1,312,807	210,338			210,347		**1,523,154**		1,312,807	210,347			210,354	1,312,807	**1,523,161**	
Depreciation & Amortization	82,966		82,966	na	na			na		**87,207**	N 12	na	na			na		**88,411**	N 12
Amortization of State ITC	(1,453)		(1,453)		-1,453	101.8%	N 12	-1,480		**-1,480**		0	-1,480	101.4%	N 12	-1,500		**-1,500**	N 12
Taxes Other Than Income	172,913	8,879	181,792	na	na			na		**182,530**	N 14	na	na			na		**182,897**	N 14
Interest on Customer Deposits	479		479		479	108.5%	N 15	520		**520**		0	520	108.5%	N 15	564		**564**	
Income Taxes	20,251	35,441	55,692	na	na			na		**56,710**		na	na			na		**57,493**	
TOTAL OPERATING EXPENSES	1,798,229	44,392	1,842,621	1,312,807	209,364			209,387		**1,848,642**		1,312,807	209,387			209,418		**1,851,026**	
													0			0		**0**	
OPERATING INCOME	68,624	55,643	124,267	na	na			na		**126,538**	N 10	na	na			0		**128,285**	N 10
								0		**0**			0			0		**0**	
AVERAGE RATE BASE	1,411,417	(900)	1,410,517	na	na			na		**1,436,299**	N 9	na	na			na		**1,456,127**	N 9
RATE OF RETURN ON AVERAGE RATE BASE	4.86%		8.81%							**8.81%**								**8.81%**	
REVENUE ADJUSTMENT (DIFFERENCE IN TOTAL OPERATING REVENUES)										**$8,311**								**$4,131**	

* Allocated Labor and Nonlabor of total O&M expenses based on 2009 Budget as provided in HECO-WP-101(A) in the 2009 Rate Case

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N 1 See "Nominal" Tab in Worksheet
N 2 No escalator used
N 9 Rate base in 2010 and 2011 grown by $15,177K (Estimate of coefficient for unit change in X variable (time)), based on average rate base less significant projects
N 10 Based on 2009 TY RORB = 8 81%
N 11 (Total Operating Expenses less revenue taxes+Operating Income)/(1-PUC & PSC & Franchise Tax rates-Uncoll Factor) less Other Operating revenue & Gain on Sale of Land
N 12 Index based on growth rate of average rate base. In 2010, CIP CT-1 depreciation added. In 2011, index based on growth rate of average rate base
N 13 Based on growth of O&M Expenses and Operating Income
N 14 See "Taxes" Tab in Worksheet
N 15 Based on growth rate submitted for 2009 Rate Case (Rate Case Update, HECO T-9, p 7)

Total Labor in Test Year		
2009	81,136 4	
2010	81,136 4	100 00%
2011	81,136 4	100 00%
Total NonLabor in Test Year (excluding Fuel & Purchase Power expense)		
2009	#########	
2010	#########	100 00%
2011	#########	100 00%
Total O&M (excluding Fuel & Purchase Power expense)		
2009	#########	
2010	#########	100 00%
2011	#########	100 00%
Total Operating Income		
2009	#########	
2010	#########	101 83%
2011	#########	101 38%
Total O&M Expenses (excluding Fuel & Purchase Power expense) & Operating Income		
2009	#########	
2010	#########	100 64%
2011	#########	100 49%

PUC-IR-7

At Attachment 5A page 1 of 11 of the PEG report, O&M expenses are projected to increase by $5.2 million between 2009 and 2010 and by $4.7 million between 2010 and 2011. The RAMs for 2010 and 2011 are $6.1 million and $5.4 million. Please provide step-by-step calculations on what the difference is between this portion of the RAM and O&M growth.

HECO Response:

Besides the change in O&M expenses, the RAM also includes the changes in payroll taxes (assumed to grow in proportion to the growth in labor expenses) and the changes in interest paid on customer deposits. The sum of these changes are then "grossed up" to reflect the obligation to pay revenue taxes (i.e., public service tax, gross excise tax, and franchise tax) on the additional revenue requirement that is billed to ratepayers. See Attachment 1 for a reconciliation of the HECO RAM for the years 2010 and 2011.

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Calculation of 2010 RAM (referenced from 2009 Test Year)

Total O&M Expenses (Results Tab, row 46):	
2010 escalated by GI Forecast	$1,528,341
2009 Test Year	$1,523,145
Difference	$5,196
Payroll Taxes (see Tax Tab, row 76):	
2010 escalated by Labor Expenses	$7,610
2009 Test Year	$7,330
Difference	$280
Interest on Customer Deposits (Results Tab, row 51)	
2010 escalated by Test Year growth rate	$520
2009 Test Year	$479
Difference	$41
TOTAL Differences	$5,517
Divided by 1-8.85% (PSC, Gross Excise, Franchise Taxes)	91.15%
REVENUE REQUIREMENT CHANGE	**$6,053**

Note: Additional PSC, Gross Excise, Franchise Taxes are reflected in "Taxes Other than Income" in Results tab, row 50 with payroll taxes

Calculation of 2011 RAM (referenced from Calculated 2010 Rev Reqmt)

Total O&M Expenses (Results Tab, row 46):	
2011 escalated by GI Forecast	$1,533,020
2010 Post Test Year (see above)	$1,528,341
Difference	*$4,679*
Payroll Taxes (see Tax Tab, row 76):	
2011 escalated by Labor Expenses	$7,801
2010 Post Test Year (see above)	$7,610
Difference	$191
Interest on Customer Deposits (Results Tab, row 51)	
2010 escalated by Test Year growth rate	$564
2010 Post Test Year (see above)	$520
Difference	$44
TOTAL Differences	$4,914
Divided by 1-8.85% (PSC, Gross Excise, Franchise Taxes)	91.15%
REVENUE REQUIREMENT CHANGE	**$5,391**

Note: Additional PSC, Gross Excise, Franchise Taxes are reflected in "Taxes Other than Income" in Results tab, row 50 with payroll taxes

PUC-IR-8

HECO forecasts its trended rate base to increase by $15.2 million/year plus significant projects. Please provide a detailed worksheet that produces the forecasted $10 million rate base portion of the RAM in 2010 and the $2.4 million in 2011.

HECO Response:

Please see the response to PUC-IR-6, subpart a.

PUC-IR-9

How is the proposal included in the utilities' REIS filing to increase rate base by 10% of the purchases made through the feed-in tariffs included in the RAM's rate base adjustment? Please quantify.

<u>HECO Response:</u>

The feed-in tariffs proposal that "10% of the utility's energy purchases under feed-in tariff PPA will be included in the utility's rate base through January 2015" was part of the October 20, 2008 *Energy agreement Among the State of Hawaii, Department of Business, Economic Development, and Tourism, Division of Consumer Advocacy of the Department of Commerce & Consumer Affairs, and Hawaiian Electric Companies.*[1] This feed-in tariffs proposal was not part of the utilities' REIS filing.

The feed-in tariffs proposal to include 10% of the utility's energy purchases under the feed-in tariff is not explicitly a part of the HECO Companies' rate base RAM adjustment in their decoupling proposal. However, as the HECO Companies' proposed rate base RAM includes a baseline component and a significant projects component, to the extend that 10% of the utilities' energy purchases under the feed-in tariffs will be included in the rate bases, the calculation of the baseline component of the rate base RAM will include these 10% of the utilities' energy purchases for the years these 10% are incorporated into the utilities' rate bases. Please see also the HECO Companies' response to PUC-IR-25, filed March 18, 2009, in Docket No. 2008-0273, in which the Companies suggested that the decision and treatment of this issue should be discussed as part of the design of a feed-in tariffs and should be addressed in the feed-in tariff docket.

[1] October 20, 2008 Energy Agreement at 17.

PUC-IR-10

Please discuss how the use of a future test year is consistent with the use of forecasted indexes in calculating a RAM.

HECO Response:

The HECO Companies' proposed RAM requires an annual revenue requirement projection. This would be tantamount to a forward test year in which there was unusually heavy reliance on mechanistic forecasting methods. Indexing is commonly used to forecast O&M expenses in rate cases with forward test years.

PUC-IR-11

Sales decoupling, the RAM and REIS as proposed, each either reduce total risk or shift the risk of a utility not achieving the authorized rate of return to customers. Given the changes in risk associated with these revenue adjustment mechanisms please explain:

a. Why should the utility be allowed to retain any earnings in excess of the authorized rate of return rather than these earnings in excess of the authorized level being allocated to the benefit of customers? Please suggest a mechanism that could allocate these earnings to customers?
b. Please discuss the effect the reduction and shift in risk should have on the utilities' authorized rate of return.

HECO Response:

a. The rate of return used to establish fair and reasonable rates is not a cap. The utility's actual rate of return may be above or below the authorized rate of return used to establish rates. Under traditional ratemaking, the utility may have the opportunity to keep all that is earned above the authorized rate of return. The utility also does not have any opportunity to recover earnings below the authorized rate of return without filing a formal rate case.

The Company has stated that it is willing to consider an earnings sharing mechanism if it is symmetric in the sharing of risks and rewards. To the extent that earnings result in a rate of return on equity that deviates from the authorized rate of return on equity deemed reasonable in the Company's latest rate case, under an earnings sharing mechanism, the utility and customers will share in the difference. In the HECO Companies' proposal submitted on January 30, 2009, page 40 states:

> The HECO Companies have not proposed an earnings sharing mechanism, but would be willing to consider one if it operated symmetrically both above and below a baseline and was fair to both customers and shareholders of the Companies.

In the joint Statement of Position filed March 30, 2009 by the Consumer Advocate and the HECO Companies, the Consumer Advocate and HECO Companies have included an earnings sharing mechanism ("ESM) in their decoupling plans.

b. Please see response to Appendix 2 – Question 7 filed on February 20, 2009 which addresses changes in risk resulting from decoupling, risks associated with the numerous massive and substantive projects which the HECO Companies have committed to undertake in the HCEI Agreement, and impacts on the utility's rate of return.

PUC-IR-12

HECO has suggested using Global Insight's inflators for individual input factors and no productivity adjustment. If the indexes are based upon input prices, and productivity comes from using inputs more efficiently, why isn't a productivity adjustment reasonable? Are other utilities improving their productivity and by what measure?

HECO Response:

The basic logic for RAMs is discussed in Section 2.2.2 of PEG's report, *Revenue Decoupling for Hawaiian Electric Companies*, filed January 30, 2009 as Attachment 1 of the HECO Companies' proposal. Section 2.2.2 is included in pages 10 to 15 of the referenced report. The report shows that the trend in a utility's cost is equal to the trend in the prices it pays for input prices less the trend in its productivity plus the trend in output (e.g. customer) growth. Productivity growth is not usually considered in RAM design without also considering customer and activity growth. RAM design can be simplified by assuming that productivity growth equals customer and activity growth. This assumption has been routinely used in California to design RAMs for more than twenty years and was used in the HECO Companies' January 30, 2009 proposal.

In the joint Statement of Position filed March 30, 2009 by the Consumer Advocate and the HECO Companies, the Consumer Advocate and HECO Companies have included a productivity factor of 0.76% as an offset to the labor expenses escalation index.

PUC-IR-13

Please describe how Global Insight calculates the indexes that HECO is proposing to use to adjust O&M expenses.

HECO Response:

Please see Attachment 1, which is a description provided by Global Insight. In summary, Global Insight's indexes for utility materials and service (M&S) input prices are constructed from the Producer Price Indexes (PPIs) that are calculated by the U.S. Bureau of Labor Statistics and from other indexes maintained by the federal government and respected private sources. The FERC Uniform System of Accounts for major electric utilities is first perused for descriptions of the M&S inputs that correspond to each detailed FERC O&M account[1]. Global Insight then chooses matching inflation indexes, for the inputs described in the accounts, from respected sources. These indexes are used, with equal weighting, to calculate a composite input price index for each of the detailed FERC O&M accounts. Indexes that summarize trends in the prices of the inputs covered by certain aggregations of the most micro FERC accounts are calculated from the composite subindexes with cost weights using cost data obtained from the FERC Form 1. Cost weights are appropriate since, according to index theory, these are the weights that permit the index to measure the impact of input price inflation on cost.

To illustrate the different levels of aggregation, Global Insight maintains composite M&S price indexes for the following 9 categories of distribution operation expenses:

- Supervision & Engineering
- Load Dispatching
- Station Expenses
- Lines
- Street Lighting and Signals

[1] The Uniform System of Accounts can be found in the *Code of Federal Regulation.*

- Meters
- Customer Installations
- Miscellaneous
- Rents.

and for the following nine categories of distribution maintenance expenses:

- Supervision & Engineering
- Structures
- Station Equipment
- Overhead Lines
- Underground lines
- Line Transformers
- Street Lighting & Signals
- Meters
- Miscellaneous.

Global Insight calculates from these micro level indexes summary M&S input price indexes for all distribution *operation* expenses, all distribution *maintenance* expenses, and for *total* distribution operation and maintenance expenses. The HECO Companies use indexes at this last level of aggregation in their January 30, 2009 proposal.

Global Insight also maintains indexes of trends in the prices of salaries and wages for several kinds of workers. We believe that these correspond to the following labor cost indexes maintained by the BLS:

Category	Global Insight Index	BLS Index
Utility Service Workers	CEU4422000008	Average Hourly Earnings of Production Workers - Utilities
Electric Power Generation, Transmission, and Distribution Workers	CEU4422110008	Average Hourly Earnings of Production Workers – Electric Power Transmission & Distribution
Managers and Administrators	ECIWMBFNS	Employment Cost Index for– Wages & Salaries: Management, Business & Financial
Professional & Technical Workers	ECIWPARNS	Employment Cost Index for– Wages & Salaries: Professional & Related

GLOBAL INSIGHT

Operation and Maintenance Cost Model Documentation

Introduction

The operation and maintenance cost model maintained by the Global Insight Utility Cost Information Service (UCIS) is designed to measure and project escalation in electric and gas utility O&M costs *exclusive* of direct fuel costs. As defined, the O&M indexes track cost movements resulting only from changes in the prices of the goods and services used in various O&M tasks. Cost increases resulting from capacity additions, regulatory requirements, weather, or internal organizational requirements, (which generally cause expenditures to increase faster than an examination of just price inflation would suggest), are excluded.

These sources of non-price expenditure increases are unique to each utility and are generally best accounted for separately by each company. The models, therefore, offer a way to isolate an important, and otherwise difficult to quantify, source of O&M cost escalation.

The model has been structured in two parallel sets of equations -- essentially interrelated versions. The first block of equations focuses solely on materials and services expenses (MS) while a second block adds proxies for labor expenses to form a combined labor, materials and services model (LMS). The discussion below centers on the materials and services model but is equally applicable to the labor, materials and services model. It should be noted that forecasts for only the materials and services indexes are published in the *Power Planner*, although all forecast banks and workspaces contain projections of both sets of indexes.

Uses of the O&M Model

- The model is accessible to all subscribers. Users can easily edit the model to incorporate alternative economic assumptions and company-specific information. The model is structured to meet several needs of planners in the electric and gas utility industries:

- The detailed structure of the O&M Model enables analysts to achieve greater precision in quantifying the effects of price inflation on O&M expenses. Analysis of costs at a disaggregate level can aid in anticipating and counteracting rapid cost increases in particular functional areas.

- Variable overall inflation rates as well as rapidly changing relative prices over the past fifteen years have contributed to sharp fluctuations in expenditures and revenues, causing, at times, a severe deterioration in the financial health of companies in regulated industries. The O&M model can be used to provide a sounder basis for proposing rates that would prevent further declines in the regulated company's financial position.

- The Model's structure makes it a simple task to incorporate company-specific information on relative expenditure patterns. A company model thus created can improve accuracy in measuring inflation's impact on a *particular* utility. Companies that rely heavily on nuclear power to generate electricity, for example, would be expected to face a different rate of inflation in their O&M expenses than those that generate the bulk of their power using coal-fired or combustion turbine units. With the Model, user's can choose either to employ their own accounting data, weighting the model to reflect a company-specific expenditure pattern, or they can default to the nationwide average weights embedded in the model.

- Analysts can use the Model to stimulate the impact of alternative macroeconomic scenarios or of specific assumptions about the escalation of certain commodities or services on utility O&M cost inflation. Alternative assumptions are available from the network of DRI's forecasting models or may be specified by the users themselves.

Methodology

The methodology used to specify the O&M indexes progresses through several level and relies on detailed information contained in the Federal Energy Regulatory Commission's (FERC) Uniform System of accounts for major (formally Class A and B) Electric Utilities and major (also formally Class A and B) Natural Gas Pipeline Companies. The accounts are published in the *Code of Federal Regulations*, Conservation of Power and Water Resources, Number 18, Parts 1 to 149, revised as of April 1, 1995, pages 342 to 373, and Parts 150 to 279, also revised as of April 1, 1995, pages 230 to 260.

Within the electric utility model, O&M expenses are classified by the seven major expense categories detailed in the FERC accounts: power production; transmission; distribution; customer accounts; customer services and information; sales; and administrative and general expenses. The major expense category for power production is further divided by plant type; steam, nuclear, hydro, and other (combustion turbine). For the gas model, coverage currently includes seven of the eight major expenses categories detailed in the FERC accounts: storage, terminaling, and processing; transmission; distribution; and the four customer account and administrative categories found in the electric model.

For each major expense category modeled, a composite O&M index and separate operation and maintenance component indexes are defined. Each operation and maintenance index is further delineated into subcategories corresponding to individual FERC accounts.

Steam plant operation expenses, for example, are defined at the subcategory (FERC) level by supervision and engineering expenses (FERC account 500), fuel expenses (account 501), steam expenses (account 502), electric expenses (account 505), miscellaneous steam power expenses (account 506) and rents (account 507). The fuel expense index for account 501, while modeled, is not used to form the steam plant

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operation index. Table 1 summarizes the O&M model in terms of FERC account coverage.

Table 1: O&M Model Coverage by FERC Account

Electric

Major Expense Categories	**FERC Account Numbers**
1. Power Production Expenses	
A. Steam Plant	
Operation	500-502, 505-507
Maintenance	510-514
B. Nuclear Plant	
Operation	517, 519, 520, 523, 524
Maintenance	528-532
C. Hydro Plant	
Operation	535, 537-540
Maitenance	541-545
D. Other (Combustine Turbine)	
Operation	546-550
Maintenance	551-554
2. Transmission Expenses	
Operation	560-564, 566-567
Maintenance	590-598
3. Distribution Expenses	
Operation	580-589
Maintenance	590-598
4. Customer Account Expenses	901-903, 905
5. Customer Service and Information Expenses	907-910
6. Sales Expenses	911-913, 916
7. Administrative and General Expenses	
Operation	921, 923-925, 926 928, 930, 931
Maintenance	935

Table 1 continued

Gas

Major Expense Categories	**FERC Account Numbers**
2. Natural Gas Storage, Terminaling and Processing Expenses	
A. Underground Storage	
Operation	814-822, 824, 826
Maitenance	830-837
B. Other Storage	
Operation	840-842.2
Maintenance	843.1-843.9
C. LNG Terminaling and Processing	
Operation	844.1-844.8, 845.1-845.3, 846.2
Maitenance	847.1-847.8
3. Transmission Expenses	
Operation	850-857, 859-860
Maitenance	861-867
.4 Distribution Expenses	
Operation	870-881
Maitenance	885-894
4. Customer Account Expenses	901-903, 905
5. Customer Service and Information Expenses	907-910
6. Sales Expenses	911-913, 916
7. Administrative and General Expenses	
Operation	921, 923-925, 926 928, 930, 931
Maintenance	935

As defined in the account descriptions, each FERC index contains certain types of materials and services -- i.e., the basic cost elements -- required to perform the necessary operation and maintenance tasks. These basic cost elements are assigned a detailed price index, based on analysis by the UCIS staff, from among those published by the Bureau of Labor Statistics, Bureau of Economic Analysis or private industry data sources

To generate forecasts of each FERC account, projections of the selected price indexes are prepared by the Cost Information Service and DRI's U.S. Economic Service. The FERC account indexes are then aggregated to form indexes reflecting price changes in plant operation and plant maintenance. These operation and maintenance indexes are then combined into plant composite index for each major expense category. The final step is the aggregation of all the major expense category indexes into overall electric and gas O&M indexes.

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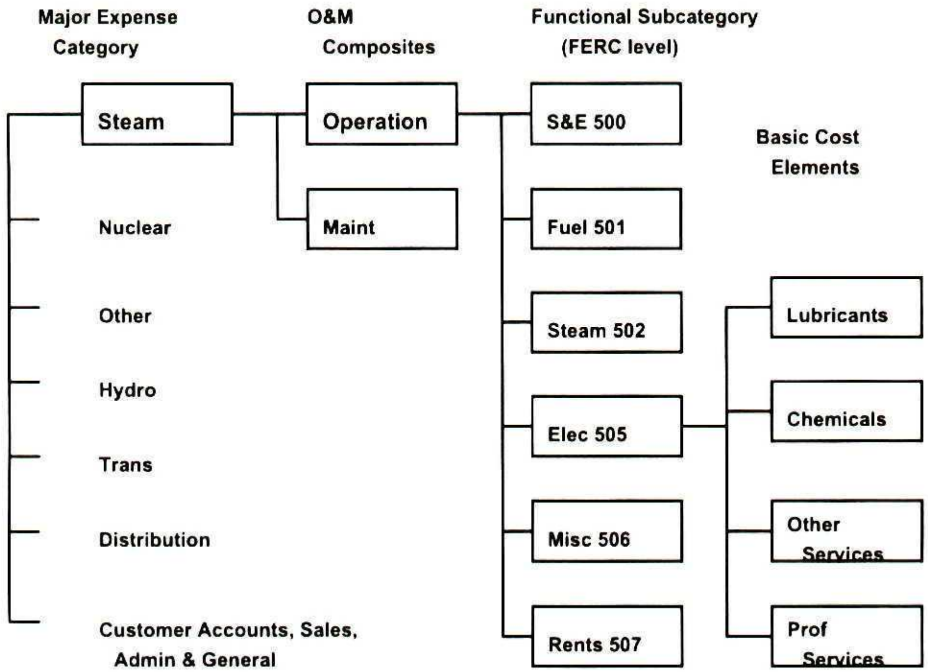
The relative weights used in compiling the model are derived from expenditure data for major electric utilities and major natural gas pipeline companies published by the Department of Energy.* (Because of the lack of data detailing relative expenditures below the FERC level, all basic cost indexes within each FERC level equation are assigned equal weights). Chart 1 presents a simplified diagram showing the structure of the materials and services model (with specific reference to Steam Plant Operation costs) from the overall O&M index to the basic cost components in a FERC account.

Chart 1: The Structure of the Electric O&M Model



An Example of Methodology

This example uses FERC Account 537 - Hydraulic Power Generation, Operation, Hydraulic Expenses, within the major expense category of hydraulic power. The description of this account can be found on page 350 of Conservation of Power and Water Resources, Parts 1 to 149. It reads:

Items

Labor:

*Statistics of Privately Owned Electric Utilities in the United States, 1994, January 1994, U.S. Department of Energy, Energy Information Administration, Washington, D.C. 20461
and Energy Data Report: Statistics of Interstate Natural Gas Pipeline Companies, 1991, January 1992, U.S. Department of Energy, Energy Information Administration, Washington, D.C. 20461.

1. Supervising Hydraulic operation.
2. Removing Debris and ice from trash racks, reservoirs, and waterways.
3. Patrolling reservoirs and waterways.
4. Operating intakes, spillways, sluiceways, and outlet works.
5. Operating bubbler, heater, or other deicing systems.
6. Ice and log jam work.
7. Operating navigation facilities.
8. Operations relating to conservation of game, fish, and forests, etc.
9. Insect control activities.

Materials and expenses

10. Insect control materials.
11. Lubricants, packing, and other supplies used in operation of hydraulic equipment.
12. Transportation expense.

Focusing on the "Materials and Expenses" section, items 10 through 12 list the expenses that should be recorded in this account and suggest the cost elements that should be included in forming a cost index. Based on this information, and on analysis by UCIS, the following price indexes are assigned to the listed cost items:

Item	Proxy
10. Insect Control Materials	Producer Price Index, Industrial Chemicals (WPI061NS)
11. Lubricants, packing, etc.	Producer Price Index, Finished Lubricants (WPI0576NS)
12. Transportation expense	Consumer Price Index, Private Transportation, (CUSA41NS)

Using this correspondence and assigning equal weights for each of the indexes identified, the FERC account cost index is defined. A similar procedure is used for the other FERC accounts included in hydraulic operation expenses. These FERC account indexes are then combined using weights derived from Department of Energy data to yield the total hydraulic operation cost index.

Construction of the labor materials, and services (LMS) version of the O&M model proceeds through one additional level of aggregation. At the FERC level, an index for labor expenses is matched with the materials and services index. Returning to or example above, the materials and services index form for account 537 is combined with a composite labor expenses index, JLAB, to form the FERC account index used in the labor, materials, and services model. The composition of the labor expenses index at the subcategory level varies with the description of the labor items in each FERC account. Labor expenses in the supervision and engineering accounts are measured with indexes

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reflecting the higher percentage of professional staff used in these functions. For account 920, Administrative and General Salaries, an employment cost index for managers and administrators is used as a proxy for labor expenses. Indexes representing escalation in wages for production workers are typically used in the remaining accounts. Again, weights derived from Department of Energy data are used to form the major expense and total O&M indexes for the labor, materials, and services model.

Fixed Versus Variable Costs

While the O&M model is structured along lines dictated by the FERC Uniform System of Accounts, clients have on occasion requested assistance in developing indexes, using the detailed already found in the model, which match "fixed" and "variable" cost concepts. At first glance this might seem to involve a wholesale reworking of the model's structure. A reading of the FERC accounts, however, will reveal that for the most part the operation indexes reflect "variable" costs while the maintenance indexes measure what might be termed "fixed" expenses.

The FERC account descriptions for the operation accounts clearly indicate that expenses would vary in direct proportion to the scale of operation. Taking a production plant off-line, for example, would drop most expenses in these cost categories to zero. Within steam power operation, for example, fuel costs (account 501) would obviously decline, if not be eliminated. Other operation categories would also be affected. Fuel handling and preparation expenses (found in account 502, steam expenses), would fall off. Purchases of purification chemicals, feed water, and lubricants for conveying equipment would be negligible.

Descriptions of the maintenance accounts, although loosely defined, tend to list expenses which would be incurred whether a facility is operating or not. For instance, maintenance inspections and equipment tests needed to certify the integrity of a plant are required even if the facility is being held off-line in reserve. Likewise, routine servicing might be required in conjunction with maintenance inspections whether equipment is being operated or not. In this sense these expenses are "fixed".

The use of the operation indexes to track and forecast escalation in variable costs or the maintenance indexes for fixed costs may, in some instances, require more detailed analysis. Clients having specific questions should simply contact the Utility Cost Information Service for assistance.

PUC-IR-14

Please complete the attached spreadsheets.

HECO Response:

Attachment 1 (confidential) provides the spreadsheets as requested for HECO, HELCO, and MECO, respectively. As this attachment includes financial information for future years which is nonpublic information that should not be disclosed publicly as it might trigger requirements under the rules and guidelines of the Securities and Exchange Commission and/or the New York Stock Exchange that information that would be meaningful to investors be released to all investors, if the information is disclosed beyond a limited number of "insiders" (including persons required by agreement to maintain the confidentiality of the information and to use it only for proper purposes), they are being filed under the Protective Order issued on January 9, 2009 in this proceeding. If these attachments are not filed under the Protective Order in this proceeding, the disclosure of nonpublic financial information might trigger disclosure requirements under the rules and regulations of the Securities and Exchange Commission and/or the New York Stock Exchange.

The HECO Companies completed these spreadsheets strictly for illustrative purposes by using information and the same methodology contained in their January 30, 2009 proposal. In the HECO Companies' January 30, 2009 proposal, DSM/IRP and fuel and purchased power expenses were deducted from total operations and maintenance ("O&M") cost to derive the O&M cost subject to RAM adjustment. Similarly, DSM/IRP and fuel and purchased power revenues were deducted to derive the net revenue figures. The revenue and expense figures for

2009[1] to 2013 are based on the latest budgets approved by management for HECO and MECO and based on 2008's latest budget update for HELCO[2]. The following exceptions are noted:

1. As the HECO Companies' current budget only extends to 2013, we are unable to complete the column for the year 2014.
2. The HECO Companies currently do not have any forecast for revenues to be recovered via the REIS surcharge. Any forecast at this time would be speculative as the Commission has not issued a final decision and order defining the framework of the surcharges requested by the HECO Companies for the Renewable Energy Infrastructure Program ("REIP")/Clean Energy Infrastructure Surcharge ("CEIS") in Docket No. 2007-0416 and the Advanced Metering Infrastructure ("AMI") Surcharge in Docket No. 2008-0303. As such, rows 26, 27, and 28 cannot be completed.
3. The HECO Companies do not track changes due to inflation, productivity, exogenous factors, and carrying costs. As such, rows 16, 17, 18, and 19 cannot be completed.
4. The HECO Companies are not proposing a revenue per customer decoupling mechanism. As such, rows 35, 36, and 37 cannot be completed.
5. The HECO Companies are not proposing a decoupling mechanism which includes sales decoupling only and without a RAM component. As such, rows 39, 40, and 41 are not completed.

[1] Since HECO has filed a 2009 rate case in Docket No. 2008-0083, HECO's 2009 figures reflect the 2009 test year rate case numbers.

[2] HELCO's latest 2008 budget update is used to eliminate "double counting" the efficiency factor due to the planned in service date of Keahole ST-7. The efficiency factor will be reset in HELCO's 2009 rate case filing. Using the 2009 budget approved by the BOD as the starting point for RAM escalation in the future years would overstate HELCO's earnings.

6. To the extent the HECO Companies are unable to complete the requested rows and column, "n/a" is denoted (versus "N/A" as originally provided in the template.)

For the third sheet tab which requests for the annual revenue requirement associated with projects not covered by the REIS, the HECO Companies applied the same threshold in their January 30, 2009 proposal for significant projects and listed the applicable projects which are considered significant projects.[3]

[3] Significant projects are defined as capital projects that are larger than $20,000,000 for HECO, $10,000,000 for HELCO and MECO, and $20,000,000 for the HECO Companies on a consolidated basis. All thresholds are net of CIAC. HECO Companies January 30, 2009 proposal at 25, fn 11.

Confidential Information Deleted Pursuant To Protective Order, Filed on January 6, 2009.

Attachment 1 contains confidential information and is provided subject to the Protective Order filed on January 6, 2009 in this proceeding.

PUC-IR-15

Please quantify the loss in estimated revenues associated with the proposed decoupling method to the estimated revenues generated through the proposed RAM (e.g., Attachment 5A page 1 of 11 of PEG's Revenue Decoupling for Hawaiian Electric Companies).

HECO Response:

Per clarification provided in the Commission's memorandum dated March 27, 2009, Attachment 1 is a summary which compares the estimated revenues associated with the proposed decoupling method to the estimated revenues generated through the proposed RAM. The estimated revenues associated with the proposed decoupling method is the sum of amounts found in rows 8 and 9 of either Sheet 1 or Sheet 2 of the attachments to the HECO Companies' response to PUC-IR-14. The estimated revenues generated through the proposed RAM are the amounts found in row 31, Sheet 1, in the attachments to the HECO Companies' response to PUC-IR-14, after adjustment to remove reductions for revenue taxes and income taxes.

Estimated Revenues Associated With Decoupling and RAM

		2009	2010	2011	2012	2013
HECO	PUC-IR-14 Row 8	$ (7,913)	$ (4,470)	$ (595)	$ 4,184	$ 5,172
	PUC-IR-14 Row 9	$ 2,937	$ 2,754	$ 3,547	$ 3,775	$ 3,916
	Estimated Revenues Associated with Proposed Decoupling Method	$ (4,976)	$ (1,716)	$ 2,952	$ 7,959	$ 9,088
	PUC-IR-14 Row 31	n/a	$ 4,623	$ 7,021	$ 15,623	$ 25,505
	Gross Revenue and Income Taxes	n/a	$ 3,688	$ 5,601	$ 12,464	$ 20,348
	Estimated Revenues Generated Through Proposed RAM	n/a	$ 8,311	$ 12,622	$ 28,087	$ 45,853
HELCO	PUC-IR-14 Row 8	$ (3,656)	$ (1,642)	$ (34)	$ 50	$ 388
	PUC-IR-14 Row 9	$ 1,524	$ 1,275	$ 1,972	$ 2,807	$ 3,055
	Estimated Revenues Associated with Proposed Decoupling Method	$ (2,132)	$ (367)	$ 1,938	$ 2,857	$ 3,443
	PUC-IR-14 Row 31	n/a	n/a	$ 1,002	$ 2,115	$ 3,284
	Gross Revenue and Income Taxes	n/a	n/a	$ 798	$ 1,685	$ 2,616
	Estimated Revenues Generated Through Proposed RAM	n/a	n/a	$ 1,800	$ 3,800	$ 5,900
MECO	PUC-IR-14 Row 8	$ (3,322)	$ (910)	$ 1,465	$ 1,849	$ 1,155
	PUC-IR-14 Row 9	$ 1,221	$ 1,611	$ 2,217	$ 2,556	$ 2,834
	Estimated Revenues Associated with Proposed Decoupling Method	$ (2,101)	$ 701	$ 3,682	$ 4,405	$ 3,989
	PUC-IR-14 Row 31	n/a	n/a	$ 1,447	$ 2,894	$ 4,342
	Gross Revenue and Income Taxes	n/a	n/a	$ 1,153	$ 2,306	$ 3,458
	Estimated Revenues Generated Through Proposed RAM	n/a	n/a	$ 2,600	$ 5,200	$ 7,800

PUC-IR-16

Other than the HCEI Agreement, why is a revenue per customer approach to sales decoupling inferior to a total revenue approach?

<u>HECO Response:</u>

The HECO Companies do not consider the revenue per customer approach to be inferior to the "total sales" approach discussed in the NRRI Scoping Paper. Page 11 of the NRRI Scoping Paper states that "Total sales decoupling mechanisms adjust for earnings changes associated with sales changes and do not adjust earnings for changes in costs (e.g. fuel adjustment clauses or inflation adjustments)." RAMs with no automatic escalation for changing business conditions would compel utilities to file annual rate cases since the cost of a utility almost always grows due to some combination of input price inflation and output growth. There are very few precedents for this decoupling approach. The revenue per customer approach to RAM design is preferable to the total sales approach that the NRRI Scoping Paper describes inasmuch as it at least provides an adjustment for customer growth. However, it falls short of best practice by not providing, at a minimum, an allowance for input price inflation. Some approaches to RAM design would also provide budgets for non-routine investments.

PUC-IR-17

For each decoupling proposal listed at Tables 2 and 3 of PEG's decoupling report, please describe the associated RAM approved by the jurisdictional commission. Please differentiate revenue per customer mechanisms from other RAMs.

HECO Response:

Table 2 of PEG's decoupling report, *Revenue Decoupling for Hawaiian Electric Companies,* filed January 30, 2009, as Attachment 1 of the HECO Companies' proposal, pages 24 to 31, grouped approved precedents for revenue adjustment mechanisms ("RAMs") by type of RAM: hybrid, all forecast, full indexation, inflation only, and revenue per customer freezes. Under the "Description of Revenue Adjustment Mechanism" column, detailed descriptions of the RAMs awarded were included for hybrid, all forecast, full indexation, and inflation only mechanisms.

Table 3 of the above-referenced report, page 32, included approved precedents for straight-fixed variable ("SFV") rates. Description of the SFV rate design was provided under the column with the same heading.

An expanded list of precedents can be found in the hard copy of Dr. Lowry's February 27, 2009 presentation in Honolulu, in slides 9 to 11, and 14.

PUC-IR-19

Please discuss the purpose of having separate Revenue Balancing Accounts for residential and all other customers.

HECO Response:

The purpose of separate Revenue Balancing Accounts ("RBAs") for residential and all other customers is to eliminate any potential cross-subsidization between the two groups that may arise in future decoupling adjustments where one group is on target with revenue while the other group is not. The idea is for the two groups to maintain their relative responsibility for the revenue target in the decoupling adjustments; the general rate case is the forum where the relative responsibility for the revenue requirement between residential and commercial groups is discussed.

The HECO Companies also dismissed commercial, industrial, and governmental agencies customers from having separate RBAs. Because of the limited number of customers in these customer classes, having separate RBAs for each non-residential schedule would create an undue burden in meeting the revenue target for individual customers who remain should other customers in that same schedule leave (e.g. cessation of operation, move to another rate schedule).

PUC-IR-20

Why is the RAM better considered within the decoupling docket than a rate case?

HECO Response:

The Commission has opened the decoupling docket to consider the decoupling mechanism agreed to in the Energy Agreement, which includes the RAM provision. The concept of a RAM is better considered within the decoupling docket for two primary reasons: 1) the RAM approach and methods will apply to all the HECO Companies (HECO, HELCO, and MECO), so the decoupling docket is an efficient and appropriate forum for that discussion; and 2) the initial discussion of the RAM approach and methods is unfettered by rate case issues, which allows the parties to the decoupling docket to better focus on RAM considerations.

PUC-IR-21

Why is approval of a RAM necessary at this time, other than its mention in the HCEI Agreement? Please provide a quantified response.

HECO Response:

A revenue decoupling mechanism plays an integral role in the HCEI Agreement for two fundamentally different reasons. One is the further slowdown in sales per customer growth that is expected to result from increased efforts to promote conservation and customer-sited DG. The second is to mitigate the increase in operating risk that may result from the agreement. In the short run, one source of greater risk is proposed increases in volumetric charges. In the longer run, the Company faces increased risk from greater reliance on renewable sources of energy.

The Company is proposing a true-up approach to decoupling, which is the traditional decoupling approach for electric utilities. Revenue adjustment mechanisms are almost always included in decoupling true-up plans, as Dr. Lowry discussed at length in PEG's January 30, 2009 report, *Revenue Decoupling for Hawaiian Electric Companies*. He writes that the costs of utilities almost always rise over time due to a combination of input price inflation and output growth.[1] A mechanism is therefore needed to escalate the revenue requirement between rate cases.

The RAM compensates the utilities for increases in operating and maintenance ("O&M") costs and the return on and return of investments in infrastructure between rate cases. The immediate need for the RAM is driven by the increase in these costs related to the many initiatives in the HCEI Agreement, normal input price and output growth, and to maintaining and improving service reliability with an aging infrastructure while the HECO Companies transition

[1] PEG's January 30, 2009 report, *Revenue Decoupling for Hawaiian Electric Companies*, at 7.

to incorporate more renewable energy resources into their grids and concurrently transform them into smart grids. The investments referred to above are investments related to the on-going operations of the Companies and not the investments that would be covered by the Renewable Energy Infrastructure Surcharge ("REIS"). As for investments which are recovered under REIS, the associated O&M expenses for these projects are to be recovered under base rates and not through the REIS.

There are many initiatives in the HCEI Agreement which will require additional O&M costs not recovered through REIS or other surcharges. These include: 1) labor and non-labor expenses (beyond the costs of outside consultants) to conduct wind studies, negotiate with wind farm developers for power purchase agreements, and the subsequent interconnections; 2) labor and non-labor expenses to analyze solar opportunity, negotiate with photovoltaic developers for power purchase agreements, and the subsequent interconnections; 3) labor and non-labor expenses to accommodate the expected increases in distributed generation; 4) R&D expenses and conversion to biofueling; 5) increased renewable interconnection activities due to the expected adoption of feed-in tariffs and a PV host program; and 6) costs to support the mass transit system and electric vehicles. In HECO's 2009 test year rate case, HECO has included the associated expenses for these activities in the 2009 test year. However, these expenses are tied to the developmental and implementation timelines of these projects and will increase in the later years until these projects are completed.

The HECO Companies' existing infrastructure is also very aged. In HECO's 2009 test year rate case, HECO-704 shows that the average age of its steam units is 45.7 years, reheat steam units 39.3 years, non-reheat steam units 54.3 years; while the average age of the independent power producers' plants is 18.0 years. In HECO-813, the average ages of its transmission lines are: 138kV overhead lines, 38.1 years, (with 78.2%, or 167 miles over 30+ years); 138kV underground lines, 14.7 years; 138kV transmission transformers, 32.5 years (with 66% or 31 units over 30+ years); distribution substation transformers, 31.7 years (with 58% over 30+ years). The HECO Companies must continue to invest in their aging infrastructure to ensure reliability of service while at the same time transition to incorporate more renewal energy resources and to smart grids.

Annual rate cases for the Companies are an alternative means to obtain the needed revenue requirement escalation under a decoupling plan without a RAM. This approach would involve a high level of regulatory cost at a time when the implementation of the HCEI agreement will be raising a host of new issues meriting regulatory oversight. .

There is also concern that annual rate cases would not be sufficiently compensatory. Since rate proceedings take, usually, at the very least, many months to adjudicate, it is difficult for the utilities to maintain their financial integrity. Regulatory lag, which provides test year rate relief late in the test year and limited ability to recover the return on and return of investments placed in service between rate cases, does not offer the utilities a fair opportunity to achieve their authorized rates of return. This constrains the ability of the utilities to attract the needed capital to attain the goals of the HCEI Agreement.

In the HECO Companies' capital expenditures budget reports filed with the Commission on March 4, 2009, HECO's rolling 5-year capital program jumped from $756 million for 2008-2012 to $1,125 million for 2009-2013, an increase of 49%.[2,3] HELCO's 2009-2013 capital budget is $284 million, remained virtually the same as 2008-2012's $290 million, but is much

[2] HECO's 2009 Capital Expenditures Budget filed March 4,2009, page 32.
[3] Of HECO's $1,125 million capital budget for 2009-2013, only $44 million related to the AMI project, will be recovered via surcharge. Ibid, pages 4 and 16. (The proposed AMI Surcharge is in HECO's AMI application, filed December 1, 2008, in Docket No. 2008-0303.)

higher compared to figures from 2002 to 2006.[4] MECO's 2009-2013 capital budget is $214 million, remaining virtually the same as 2004 to 2008.[5]

Furthermore, setting a target revenue requirement alone that does not change between rate cases (sales decoupling) provides no compensation to the utilities for increases in utility costs or infrastructure investments. Therefore, there is a need to allow increases in the target revenue requirement level each year. The HECO Companies proposed that this be accomplished through a RAM.

In summary, a revenue decoupling mechanism is needed to mitigate the financial consequences of slowing sales per customer and increased operating risk that will result from the HCEI Agreement. The RAM is an integral part of the decoupling mechanism. It will be needed immediately because of the expected increases in O&M expenses and investments resulting from the HCEI Agreement and additions to and maintenance of the existing infrastructure during the transition period (to incorporate more renewable energy resources and to smart grids), the high cost of annual rate cases, and the inability of traditional ratemaking to maintain the utilities' financial integrity necessary for the Companies to attract the needed capital so that they can fulfill their HCEI Agreement commitments to make financial investments to accommodate increased renewable energy and increase energy efficiency.

(Please also see HECO's response to Question #1 in Appendix 2 of the Commission's decoupling paper by NRRI.)

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[4] HELCO's 2009 Capital Expenditures Budget filed March 4,2009, page 16.
[5] MECO's 2009 Capital Expenditures Budget filed March 4,2009, page 8.

PUC-IR-22

Why is the interest rate proposed in the RAM filing the authorized return rather than the cost of commercial paper as used in California? What is the effect on the projected RAM if the commercial paper rate is used?

HECO Response:

The Revenue Balancing Account will track target revenue, including any RAM adjustments, against recorded revenue. Interest is proposed to be applied to the simple average of the beginning and ending month balance in the Revenue Balancing Account at the authorized rate of return. The HECO Companies use the authorized rate of return as the interest rate in the tracking and reconciliation of the Demand Side Management (DSM) rate adjustment and the Integrated Resource Planning (IRP) surcharge. Since the Revenue Balancing Account is a similar tracking and reconciliation process, the HECO Companies proposed to similarly use the authorized rate of return to apply to the differences between target revenue and recorded revenue.

The interest rate has no effect on the projected RAM as it is not a part of the calculation of the O&M RAM or the rate base RAM. However, the interest rate does impact the Revenue Balancing Account where the RAM is expected to be part of the target revenue and recovery of the RAM adjustment is part of the recorded revenue. In the Revenue Balancing Account, if the interest rate is based on a commercial paper rate rather than the authorized rate of return, the impact would depend on the economic and interest rate environment at the time. In the current depressed economy and extremely low interest rate environment, the accrued interest will be smaller in either case, whether the recorded revenue exceeds or falls below the target revenue. In an environment with high inflation and extremely high interest rate, as experienced in the early

1980's, the accrued interest would be larger in either case, whether the recorded revenue exceeds or falls below the target revenue.

In the joint Statement of Position filed March 30, 2009 by the Consumer Advocate and the HECO Companies, the Consumer Advocate and HECO Companies have included a 6% interest rate, the same as the HECO Companies pay for customer deposits, as the proposed interest rate to be applied to the RBA balance.

PUC-IR-23

Please compare the regulatory costs associated with the proposed RAM and rate cases every two years.

HECO Response:

Attachment 1 provides recorded historical costs as of March 24, 2009 for HECO's 2005 and 2007 test year rate cases, HELCO's 2006 test year rate case, and MECO's 2007 test year rate case. It also provides the estimated non-labor cost for HECO's 2009 test year rate case. The labor cost component reflects costs for management employees who work in various departments and divisions throughout the Company and support the rate case. Costs for management labor are included in base rates and depending on the individual departments or divisions, may or may not code all of their time to various projects[1]. For HELCO and MECO's rate cases, labor costs for HECO management employees supporting these rate cases are also included, although HECO's labor costs are not billed to HELCO and MECO via intercompany billing. The non-labor cost component represents legal (outside counsel), consultants, printing, and materials (e.g. paper and binder supplies) and inter-island travel for HELCO's and MECO's rate cases.

Attachment 2 provides very rough estimates for HECO, HELCO, and MECO under the RBA and RAM regime. Two estimates are provided. The first estimate assumes a process similar to the ECAC automatic rate adjustment clause filing with quarterly reconciliation. The second estimate assumes a process similar to the DSM automatic rate adjustment clause filing with annual reconciliation. These rough order-of-magnitude estimates also assume a "steady state" stage where the process has become routine. The costs under the RBA and RAM regime

[1] Many departments or divisions budget and "time report" their management employees at only 40 hours per week, not reflecting the overtime hours worked by the management employees without compensation.

would depend of the Commission's final decision and order providing guidance on how the RBA and RAM process should be administered, whether the rate changes can be administered via an automatic rate adjustment clause, and could vary from the rough order-of-magnitude estimates provided in this response. In the initial years of the transition to RBA and RAM regime, the costs could also be higher that the "steady state" stage due to the initial learning curve by the HECO Companies.

With the transition to the RBA and RAM regime, the change in labor costs cannot be summarily decreased in the short or intermediate term as these are management labor costs where no overtime is compensated or accounted for. The decreased management labor to support traditional rate case filing will be spent on supporting other dockets and management projects and activities. Non-labor costs could experience savings in the short and intermediate term as outside legal services, consultants, inter-island travel, and office supplies support can be reduced/eliminated with the transition from traditional rate case to the RBA and RAM regime – until the next general rate case is filed.

Traditional Rate Case Costs
(In Thousands)

	HECO			HELCO	MECO
	Total Recorded Costs 2005 Rate Case	Total Recorded Costs 2007 Rate Case	Test Year Estimate 2009 Rate Case	Total Recorded Costs 2006 Rate Case	Total Recorded Costs 2007 Rate Case
Labor	$1,366	$1,096	N/A	$1,337	$1,009
Non-Labor	$782	$874	$880	$986	$522
Total	$2,148	$1,970	N/A	$2,323	$1,531
Annual Amortization	$716	$657	$440	$774	$510
No. of Years	3	3	2	3	3

Notes:

1. HECO, HELCO, and MECO recorded data are as of 3/25/09. MECO and HELCO labor costs include HECO employees' labor costs (based on actual time reports) to support HELCO and MECO rate cases to reflect actual labor resources expended to support traditional rate case proceedings.
2. HELCO's 2006 rate case recorded labor and non-labor dollars are high due to the Keahole CT-4 and CT-5 settlement issues.
3. HECO's 2009 test year labor costs are included in base labor costs and are reflected in their respective responsibility areas.
4. HECO's 2009 test year non-labor costs of $880,000 is described in HECO-1403.

Decoupling (RBA & RAM) Cost
(In Thousands of Dollars)

	HECO		HELCO		MECO	
	If similar to		If similar to		If similar to	
	ECAC	DSM	ECAC	DSM	ECAC	DSM
Labor	30	83	30	63	30	86
Non-Labor	7	7	7	7	7	7
Total	37	90	37	70	37	93

Notes:
1. ECAC columns assume the RBA and RAM would be administered in a process similar to the monthly ECAC filing with quarterly reconciliation.
2. DSM columns assume the RBA and RAM would be administered in a process similar to the monthly DSM filing with annual reconciliation.
3. The cost of Global Insight's annual subscription fee would be allocated evenly among HECO, HELCO, and MECO.